Section 7: Natural Gas Pipeline and Storage Capacity

Introduction

The capacity of pipelines to deliver natural gas combined with the production of natural gas are two necessary components that ensure adequate supply. This section of the report describes pipeline infrastructure, capacity, storage, and expansion activities. The discussion begins with an overview of the natural gas purchasing and delivery process and the pipeline expansion and permitting processes in the United States and Canada. This is followed by an overview of the pipeline systems in Western North America and the increasing interconnectedness of the Western systems with the systems across North America. The end of the section describes individually and in greater detail the three major pipelines that affect the Pacific Northwest, including system overviews, operations, Canadian/domestic supply splits, contracted capacity, constraint points, expansion activity (recent and planned), and changes in storage.

There are three major pipelines that serve Washington State. They are the Northwest Pipeline Corporation, a subsidiary of Williams (Northwest), National Energy & Gas Transmission Gas Transmission Northwest Corporation (GTN)[1] and Duke Energy Gas Transmission (DEGT).[2] DEGT delivers gas from the gas fields in northern British Columbia and Alberta to the Washington border at Sumas. From Sumas, the gas is delivered to the Northwest pipeline system, which continues southeast to the Rocky Mountain gas fields. DEGT receives gas from Canada at the U.S. border in Kingsgate, Idaho, and then almost immediately crosses into Washington. (See Figure 7.1 for an overview map.)

The Pacific Northwest once was the near-exclusive recipient of large and otherwise isolated gas supplies in British Columbia. Over the past few years, major interconnections have been built between pipelines in the West and eastbound pipeline systems. The Alliance Pipeline, which came into operation in 2000, delivers gas from B.C. and Alberta to Chicago. The Kern River Pipeline and the Trailblazer Pipeline have provided new eastern and southern outlets for gas in the Rockies (see Figure 7.2). It can now be said that the Pacific Northwest, and in fact North America, is fully integrated into a North American pipeline system, and as a result, a North American market.

Natural Gas Purchasing and Delivery Process

Shippers, including local distribution companies, large industrial customers, and energy marketers, purchase capacity on the pipelines to deliver gas from particular suppliers and receipt points on the system to particular delivery points. Shippers can elect to purchase firm transportation, which will be available under all but emergency circumstances, or non-firm transportation, which will not be available when firm transportation usage is high. For more detailed information on this process, see Section 3 of the previous version of this study, *Convergence: Natural Gas and Electricity in Washington*, Washington State Office of Trade and Economic Development, May, 2001.

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[1] National Energy & Gas Transmission Gas Transmission Northwest (GTN) was formerly called PG&E Gas Transmission Northwest.

[2] Duke Energy Gas Transmission West (DEGT) was formerly called West Coast Pipeline

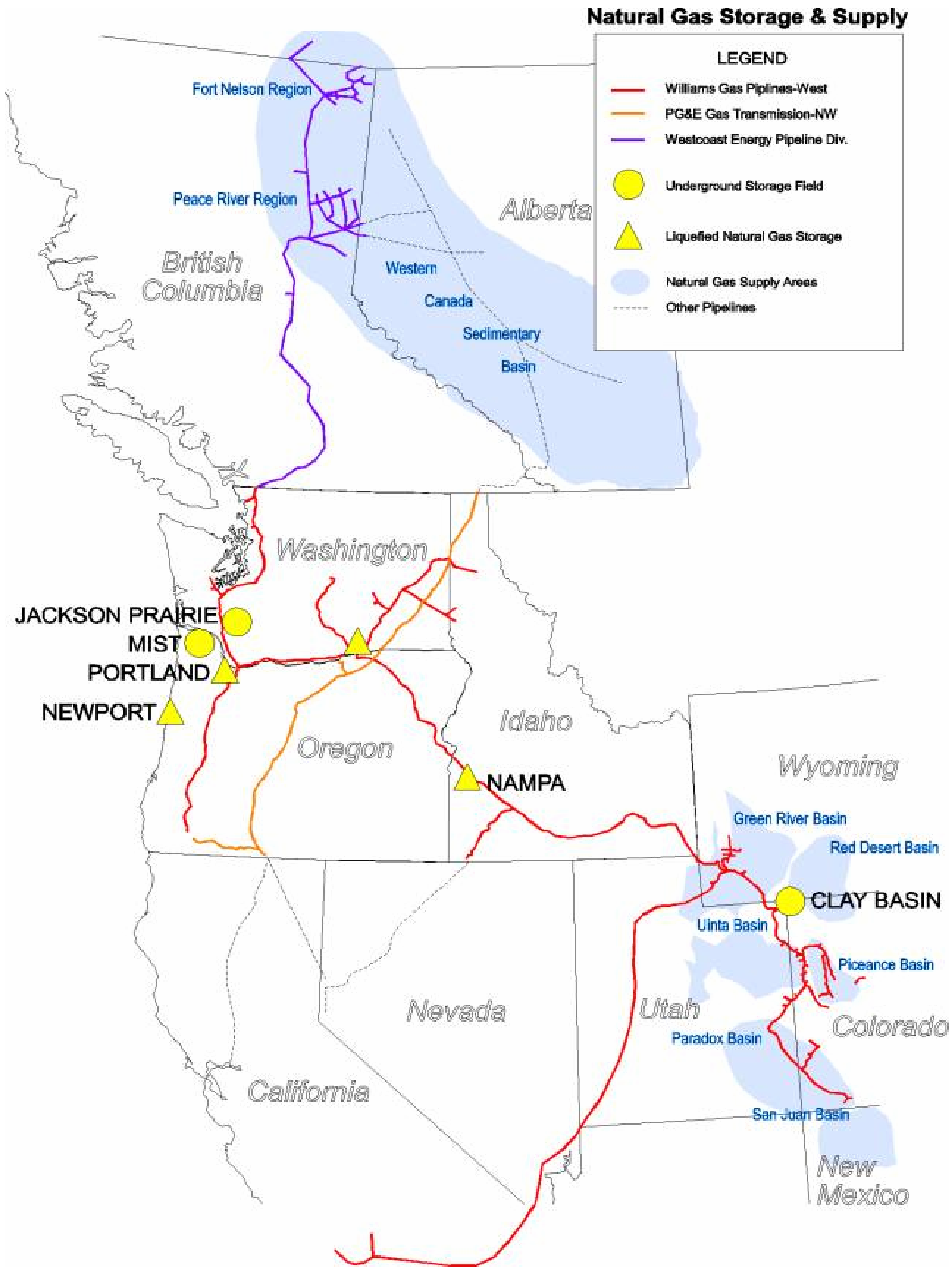


Figure 7.1: Northwest Natural Gas Storage and Supply Map

Note: Since this map was created, the name of PG&E Pipeline has changed to National Energy & Gas Transmission Gas Transmission Northwest (GTN) and Westcoast Pipeline has changed its name to Duke Energy Gas Transmission West (DEGT).

Pipeline Expansion Process

The need for additional pipeline capacity to meet demand growth can be met in several ways: Build a new pipeline, convert an oil pipeline; or expand an existing natural gas pipeline system. Building a new pipeline is much more expensive than the other two methods. The costs of new capacity can be allocated on either a *rolled in* or an *incremental* basis, as determined by the Federal Energy Regulatory Commission (FERC). If the cost of expansion is relatively minor, adding both the new costs and the new throughput to the existing rate base may result in rates that are lower than before the expansion. In this case, costs of the expansion are rolled into existing rates. If substantial new investment is required such that rolling in the expansion costs would result in rate increases for existing shippers, the costs may be assigned on an incremental basis. That is, the new shippers pay the costs of the new capacity, while existing shippers continue to pay the same rate.

Permitting process in the United States and Washington State

Typically, in addition to acquiring FERC approval for an expansion project, the environmental and construction permitting process involves working with many federal, state and local agencies. The federal agencies include the U.S. Forest Service, U.S. Department of the Interior's Bureau of Land Management, U.S. Corps of Engineers, U.S. Fish & Wildlife Service and the National Marine Fisheries Service. State agencies in Washington include the Washington State Department of Community, Trade and Economic Development Energy Facility Site Evaluation Council (EFSEC), the Office of Archaeology and Historic Preservation, and the state departments of Ecology, Natural Resources, and Fish & Wildlife. Any impacted local jurisdictions such as counties and cities may also be involved.

Depending upon the scope of the project and the issues involved, the complete permitting process for an expansion project typically takes one to two years. Likewise, the total cost of the permit process for an expansion project is dependent upon the project scope and issues. For major projects, the cost of preparing and pursuing all the required permit applications typically would be a few million dollars.

Natural gas facilities subject to EFSEC review include:

- Natural gas, synthetic fuel, gas, or liquefied petroleum gas pipelines larger than 14 inches in diameter and greater than 15 miles in length (intrastate only);
- Liquid natural gas facilities with capacity to receive an equivalent of more than 100 MMcf/day that has been transported over marine waters;
- Any underground natural gas storage reservoir capable of delivering more than 100 MMcf/day.

In Washington State very few pipelines fall under the jurisdiction of EFSEC because nearly all pipelines are inter-state, which is FERC's jurisdiction. In recent years, applications for the Cross-Cascades pipeline (withdrawn in 1995) and the Sumas 2 Energy Facility (permitted in 2003) came to EFSEC.

Permitting process in Canada

Duke Energy Gas Transmission (DEGT) is regulated by the National Energy Board (NEB) of Canada and must apply to this board for expansions of its pipeline facilities. DEGT also works with the Canadian Department of Fisheries and Oceans, and Environment Canada, both of which are federal agencies, as well as many provincial and local agencies.

When seeking approval to expand its facilities, DEGT files a facilities application with the NEB, which then assesses the need and justification for the new facilities, including available supply and market demand, the proposed project design and construction plans, the impacts on the environment, landowners, the public and aboriginal groups, and the financial impacts associated with financing the expansion. The size of the project will determine whether a public hearing is required.

There is no charge for the project application, apart from the time of the staff devoted to the regulatory process. The length of time it takes to gain regulatory approval for a project varies according to many factors including the complexity of the project and the number of interveners and stakeholders. In general, a mainline expansion is the most complex application and it takes approximately 30 months from the close of the open season to the in-service date. Smaller projects require a commensurate amount of time.

For further discussion of the permitting process in the United States and the Federal Energy Regulatory Commission's role, see Section 3 of *Convergence: Natural Gas and Electricity in Washington* (OTED, 2001).

Western North America Pipeline System Overview

International and Inter-Regional Pipeline Capacity and Expansion

Both Northwest Pipeline and GTN, the two pipelines that serve Washington, are connected to major gas transmission lines in Canada. Northwest Pipeline receives gas supplies from DEGT and GTN, and GTN receives supplies from TransCanada Pipeline. Both DEGT and TransCanada are connected to gas gathering systems in the producing regions of British Columbia and Alberta. Both of these pipelines are also connected to systems that serve all of Canada and much of the northern half of the United States, as shown in Figures 7.1 and 7.2. The map in Figure 7.3 shows the relative capacities of these pipelines from a national perspective.

Table 7.1: Origin of Gas Serving the Northwest

Pipeline	Canadian Gas	Domestic Gas
Northwest Pipeline	66%	33%
GTN	92%	8%

The Alliance Pipeline, built in 2000, delivers 7.2 bcf/day from Northern British Columbia to the Chicago area, serving Canada and the Midwest along the way. It has been operating near capacity since it first came on line. The TransCanada pipeline spans nearly the entire width of Canada from the Alberta/Saskatchewan border east to Quebec/Vermont. In 2002, deliveries to export border points comprised approximately 53 percent of total deliveries. These two Canadian systems have ready access to Midwestern and Eastern markets, as well as the Pacific Northwest.

Northwest Pipeline is also connected to the major supply regions in the Rocky Mountains and relies on this region for approximately one-third of it supply, as shown in the inset table above. In Figure 7.2 below, it is apparent that recent additions in the Kern River system and the Trailblazer system compete directly for supplies with Northwest Pipeline. These two pipelines provide major new connections to markets in California and on the East Coast. The 900 MMcf/day Kern River Transmission system expansion came on line in May, 2003, to transport natural gas from Wyoming to California and Nevada. Kern River's market is comprised to a large extent of power generators serving summer cooling needs in California.

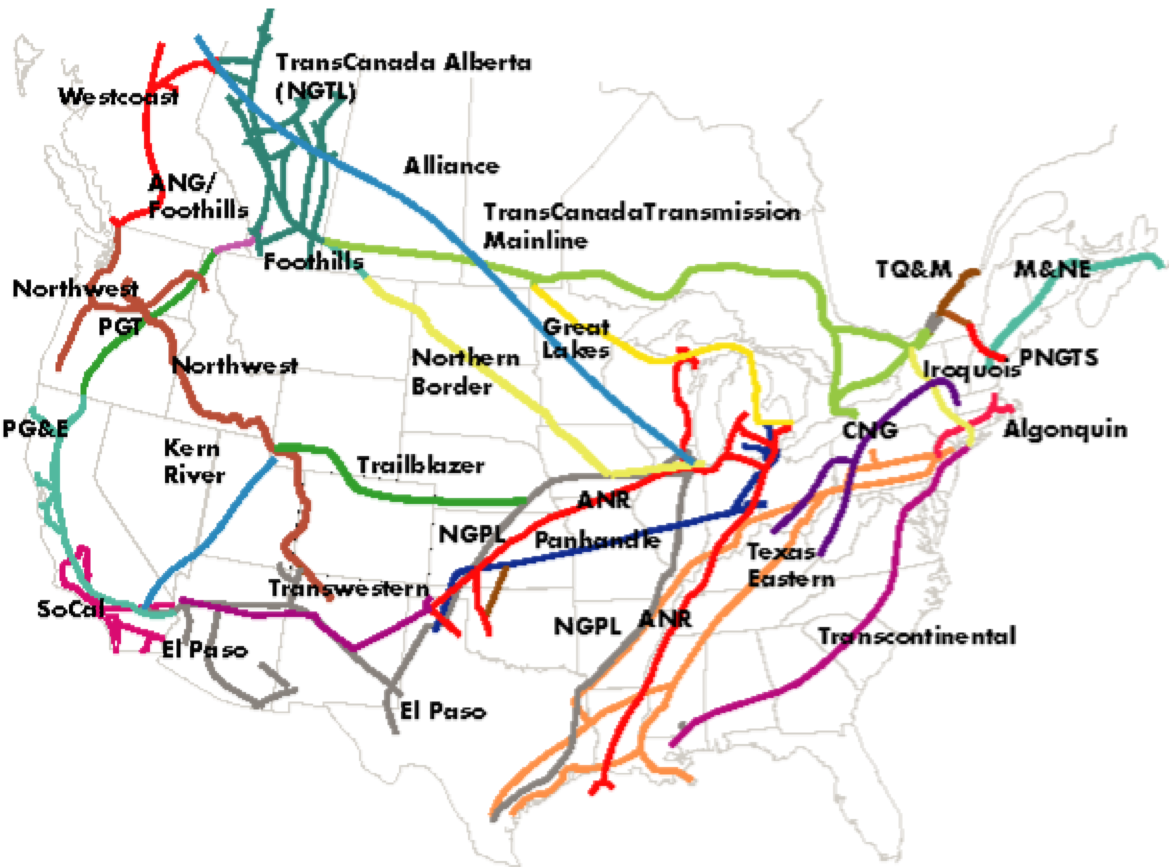


Figure 7.2 Major North American Pipelines

Source: National Energy Board of Canada - website: http://www.neb.gc.ca/energy/images/gasmap_e.gif

Note: Since this map was created the name of PG&E Pipeline has changed to National Energy & Gas Transmission Gas Transmission Northwest (GTN).

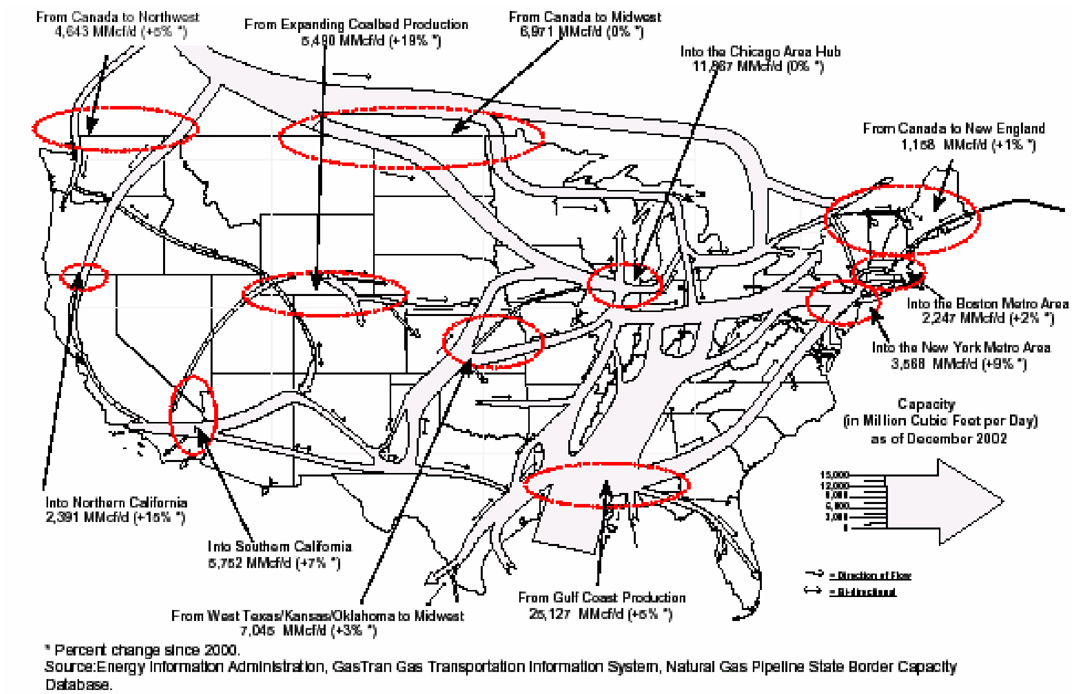
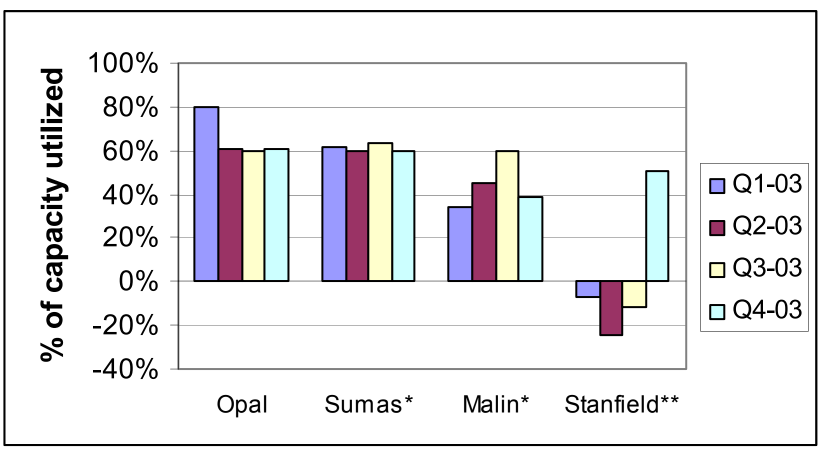


Figure 7.3 Major Natural Gas Transportation Routes and Capacity Levels at Selected Locations, U.S.

Source: Energy Information Administration
http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2003/Pipenet03/ngpipenet03.pdf

Table 7.2 below shows pipeline capacity utilization rates throughout 2003. The Kern River Expansion Project, discussed later in this section, went into effect in May of 2003 and increased flows through Stanfield, Oregon.

Table 7.2 Pipeline Utilization Rates



Source: Natural Gas Week and Bentek Energy
* Net flow
** Capacity delivering to NW is 630 MMcf/d; receiving from NW is 200 MMcf/d. A negative utilization rate connotes that the flow is toward PGT and the utilization rate calculation is based on the receipt delivery into PGT.

Development of a Continental Market for Natural Gas

Along with the increased ability of gas to flow both east and west comes increased risks and benefits to the Northwest. In recent years, the Northwest has sustained lower gas prices than eastern markets. Integration of the Canadian and Rocky Mountain supply basins with the North American market has resulted in the emergence of a "North American" price in all regions rather than a "regional" price in areas such as the Rockies, Western Canadian Sedimentary Basin (WCSB) and end use markets of the Pacific Northwest. Prices still vary but the difference between gas trading hubs is much smaller than in the past. (See Section 6 for discussion of prices.)

The Northwest and GTN pipelines are transporters of gas (they don't actually own all of the gas that they carry) and are affected by price insofar as the price affects pipeline flows. For example, GTN pipeline flows will be influenced by the price difference between AECO (a major gas trading hub in Alberta, connected to the TransCanada Pipeline) and Malin, Oregon, where it connects with Northwest Pipeline. On Northwest, price differences between Canadian and domestic gas will impact displacement.[3] Displacement is the ability of a bi-directional pipeline such as Northwest to deliver Canadian gas to the southern end of the pipeline and Rocky Mountain gas to the northern end of the pipeline by essentially offsetting the two – physically, the contracted gas couldn't flow in opposite directions over the same pipe. Price signals are considered leading indicators of the location and timing of needed incremental pipeline infrastructure enhancements. However, other signals, such as high load factor—an indicator of usage—and increased prices in other industries, such as spark spread in the power generation industry, will also spur expansion.

Pipeline Expansions into Producing Fields

Alaska

As of January 1, 2000, the Alaska Department of Natural Resources estimated the state's remaining recoverable natural gas reserves at 33.5 trillion cubic feet of gas. Production from natural gas fields in the Cook Inlet Basin currently totals more than 200 Bcf/yr. This production serves local energy needs and has been exported as liquefied natural gas (LNG) to Tokyo Electric on long-term contract since 1969.

Currently, pipelines—or pipelines in combination with LNG plants—are the options under consideration by the major producers and pipeline companies for bringing North Slope gas to market. There are three possible routes to move North Slope gas to market. They are the Alcan Highway Route, the Over-the-Top Route and the All-Alaska route. See Figure 7.4. Also under consideration is the possibility of additional LNG facilities. The state, in cooperation with energy companies, has studied the subject of pipeline development periodically over the last 25 years. The most recent study was conducted in 2002 and focuses on the options for state contributions for funding the various options.[4]

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[3]See Section 3 of the earlier version of this report, *Convergence: Natural Gas and Electricity in Washington* (Washington State OTED, May, 2001) for in-depth information about displacement.

[4]*State Financial Participation in an Alaska Natural Gas Pipeline* http://www.arcticgaspipeline.com/Reference/Documents&Presentations/A-legislature/Final%20report2.pdf

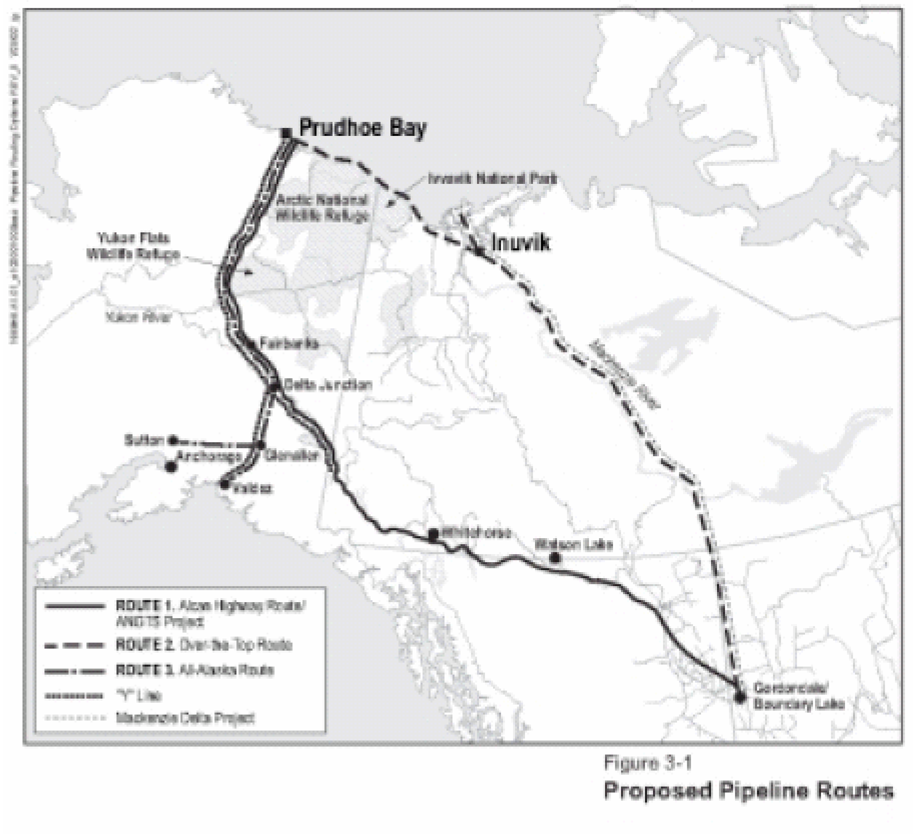

Figure 7.4 Proposed Alaskan Pipeline Routes

Below is an excerpt from the most recent study, conducted by the state of Alaska in 2002, which looked at the feasibility of state assistance in financing Alaska pipeline development.

> *To construct a multi-jurisdictional pipeline and get it financed in a timely manner requires regulatory approvals, a known and agreed-upon tariff structure, an approved pipeline route and set of initial rates, and transportation agreements that have a term and volume to allow financing and that mirror each other by jurisdiction and in receipt and delivery point. Each section of an integrated, multi-jurisdictional pipeline needs to have understood contract terms that match adjoining upstream and downstream facilities. This includes transportation volumes (size of pipe), gas quality standards (type of gas), known tariff structure (the cost to move the gas from Point A to Point B), and simultaneous service. Each piece of the pipe must be operational concurrently, must physically be capable of moving the volumes nominated by its shippers or upstream pipeline, and be able to deliver like volumes into downstream pipelines or to downstream customers. The contract volumes, terms, and titles need to match. As noted above, under ANGTA [*Alaska Natural Gas Transportation Act*] these issues were largely*

> *negotiated as part of the supply arrangements assumed by the pipelines. In today's world, this might not work.*
> *…The manner by which firm capacity would be obtained for the Alaska pipeline and its alignment with existing downstream pipeline firm capacity is unclear. This might be the most significant issue surrounding the economic and commercial viability of building these pipeline facilities.*

The state of Alaska is granted federal price support in the current version of the National Energy Bill (2003) to assist the development of any of these pipelines. At the time of this writing (early 2004) the bill has not been approved.

Northwest Pipeline System

The majority of information contained in this section on the Northwest Pipeline originated from the pipeline company itself via a survey conducted by the Community Trade and Economic Development Energy Policy Division and its contractors. The company was asked to provide information about the impact of new pipelines on its business, the ratio of gas from Canada versus the Rocky Mountains, major receipt points, largest shippers, capacity utilization, constraints, expansion plans, permitting process, storage and long-term plans.

System Overview

The Northwest Pipeline Corporation, a subsidiary of Williams, owns and operates a transmission system extending from points of interconnection with El Paso Natural Gas Company and Transwestern Pipeline Company near Blanco, New Mexico, through the states of New Mexico, Colorado, Utah, Wyoming, Idaho, Oregon and Washington, to the Canadian border near Sumas, Washington, where it interconnects with the facilities of both DEGT and Terasen Sumas, Inc.

Northwest Pipeline is a one-third owner of the Jackson Prairie Storage Project in Lewis County, Washington, and also owns and operates the Plymouth LNG facility in Benton County, Washington, both used by Northwest Pipeline to provide contract storage services. To assist in balancing its transportation services, Northwest Pipeline also has contracted for underground natural gas storage capacity from Questar Pipeline Company in the Clay Basin Field in Daggett County, Utah.

System Operations

Northwest Pipeline is a bi-directional pipeline that relies on a combination of physical and displacement capacity to meet firm contract commitments. This allows for maximum utilization of pipeline capacity, achieving natural gas flows into and out of the pipeline system that are much higher than one-way physical capacity would allow. Because Northwest Pipeline has delivery and receipt points in a number of locations throughout the western states, customers in the southern portion of the system can contract for delivery of Canadian gas and those in the North can contract for gas from the Rocky Mountains or the San Juan Basin in New Mexico. Contracted gas flowing in opposite directions over the same pipeline segment partially offset each other, thus all the gas from Canada does not necessarily have to flow to the southern part of the system and vice versa. This phenomenon is called *displacement*.

Canadian/domestic gas supply split

Canadian gas enters the Northwest system at Sumas from the DEGT Pipeline and at Starr Road, Palouse and Stanfield from the GTN Pipeline. Customers in the Pacific Northwest have contracted for approximately one-third of domestic supply and two-thirds of Canadian supply.

On Northwest's system, the percentage of supplies from Canadian and domestic sources is significantly influenced by pricing differentials between the basins. The actual (as opposed to contractual) Canadian/domestic split changes as price changes. For example, during the winter of 2002-03 domestic gas was far cheaper than Canadian gas, and the Kemmerer corridor (western border of Wyoming, near Idaho) was flowing consistently over physical capacity. However, Northwest was able to use its balancing flexibility at Jackson Prairie to mitigate customer impacts. Another effect of low domestic prices is that Northwest delivered large volumes of gas to Stanfield. Much of the time Stanfield delivers Canadian gas to Northwest.

Figure 7.5 illustrates the changing Canadian/domestic actual supply split for the past few years. Note that the data for 2003 does not yet reflect the full impact on price of the Kern River Expansion. (The graph excludes storage.)

On May 1, 2003, the Kern River Expansion went into service. Gas that had been trapped behind bottlenecks in the Rockies now has access to markets in California. Domestic gas prices rose almost immediately to meet, and ultimately exceed, the Sumas gas price. Naturally, as prices rose, flows through the Kemmerer, Wyoming, corridor plummeted. However, as fall progressed into winter, the gas prices of Canadian and domestic supplies roughly converged and domestic and Canadian supplies became more balanced. Since May 2003, both Canadian and Rockies prices have traded at a discount to the NYMEX price, but both have tracked NYMEX volatility.

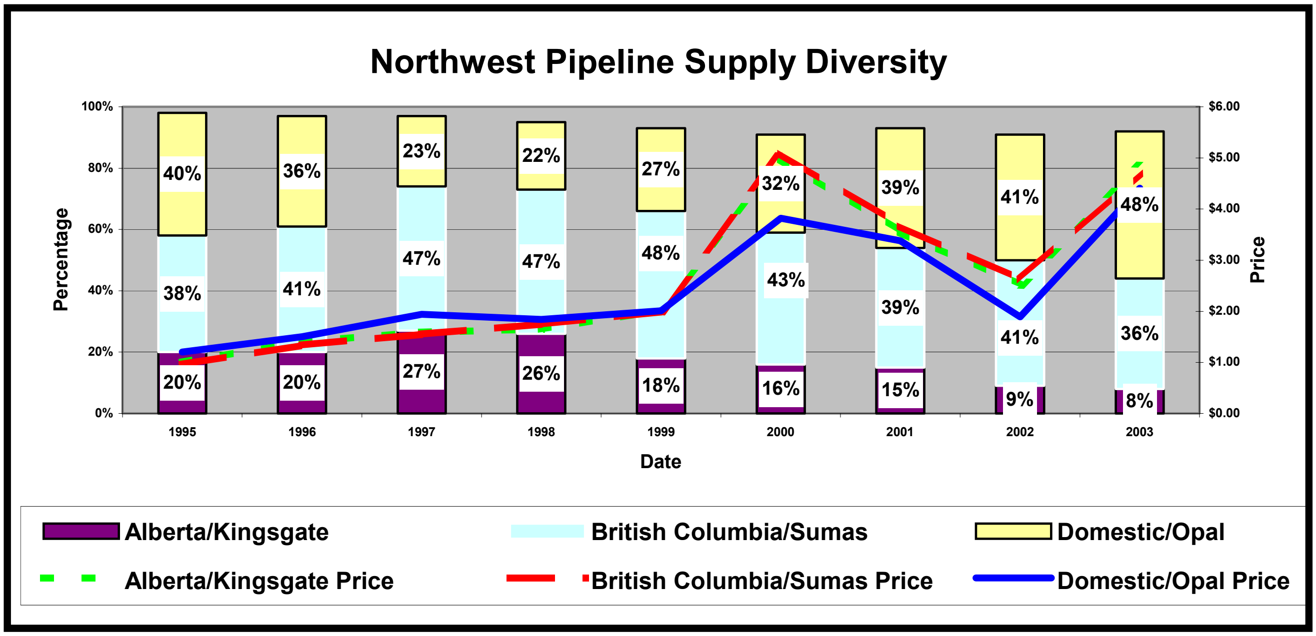

Figure 7.5: Northwest Pipeline Supply and Average Price Source: NW Pipeline

Shippers, Contracts and Delivery Points

Table 7.3 below shows the major receipt points along Northwest Pipeline's system.

Table 7.3 Contracted Capacity at Major Receipt Points

Location	Receipt Point Firm Capacity (MDth/day)
Sumas *	1,314
Starr Road**	165
Stanfield**	638
Palouse	20
Kemmerer**	721
Total w/o Storage	2858
Jackson Prairie***	1000
Plymouth LNG	300
Total Storage	1,300

* Capacity after the Evergreen Expansion went into service in October 2003.
**Kemmerer can be a mainline constraint between domestic receipt points and the Pacific Northwest. This number reflects contracted capacity. Physical capacity after the Rockies Expansion increased to 653 thousand decatherms/day.[5] Northwest's system is dependent upon approximately 75 MDth/day of displacement flow. If the entire northbound contractual capacity of 721 MDth/day were to get scheduled without any gas

[5] Thousand decatherms (MDth). A decatherm is equal to a million British Thermal Units (Btu).

flowing south (i.e. displacement gas), then Northwest would have to call a general operational flow order (OFO).
***Capacity includes a maximum of 880 MDth firm 120 MDth best efforts

Table 7.4 below shows the top reported shippers on Northwest's system based on contracted demand.

Table 7.4 Top Ten Shippers on Northwest Pipeline (Contracted)

Companies*	TF-1 Maximum Daily Quantity (MDth/day)
Puget Sound Energy, Inc.	456
Northwest Natural Gas Company	352
Pan-Alberta Gas (U.S.) Inc.	243
Cascade Natural Gas Corporation	208
Avista Corporation	200
Duke Energy Trading And Marketing L.L.C.	188
Intermountain Gas Company	120
Chehalis Power Generating Limited Partnership	90
Sierra Pacific Power Company	69
Southwest Gas Corporation	68

*Includes long-term firm base contract shippers

Subscribed Capacity and Load Capacity Factor

Each day, shippers with contracted capacity nominate the volume of gas they will need. Generally, the daily nominations are less than contracted capacity. The average ratio of nominated flows to total base contract receipt capacity for markets in the Pacific Northwest is approximately 66 percent. The load factor on different segments of the system can vary due to pricing dynamics, constraints on the system, and shipper nominations for specific points of receipt and delivery.

Major Physical Constraint Points

Northwest relies significantly on displacement to meet its contract obligations to transport Canadian and domestic gas on its bi-directional system. If transportation nominations are excessively skewed in reliance upon any one major supply source for any reason (for example, price disparities between Canadian and domestic supplies), constraints can occur. The major potential constraint points on Northwest's system are south through the Chehalis, Washington, corridor and north through the Roosevelt, Washington, and Kemmerer, Wyoming, corridors. As discussed below, Northwest has recently completed projects to reduce reliance on displacement through both of these constraint points.

Expansion into New Production Areas

Northwest has been working with numerous producers and other pipelines to provide additional access to growing Rockies supplies.

Changes in Storage Capability

The Jackson Prairie Project in Lewis County, Washington, is operated by Puget Sound Energy on behalf of the three joint owners, Northwest, Puget and Avista. In August 2002, the project operator received FERC approval to implement a phased water withdrawal/gas injection storage capacity expansion project. The authorized expansion totals 10.5 Bcf over the 2002-2008 period (6.3 Bcf working gas plus 4.2 Bcf cushion gas). Only Avista participated in the 2002 expansion phase of approximately 1.4 Bcf (60 percent working and 40 percent cushion). The 2003 through 2007 expansion phases are anticipated to be approximately 1.75 Bcf each (1.05 Bcf working plus 0.7 Bcf cushion). The 2008 phase then will complete the authorized expansion levels. Northwest's one-third share of the 2003 expansion phase storage capacity was approximately 0.475 Bcf (0.285 Bcf working gas plus 0.190 Bcf cushion gas). By the completion of the expansion project in 2008, it is anticipated that Northwest's share of the storage expansion capacity will total approximately 3.5 Bcf (2.1 Bcf working plus 1.4 Bcf cushion).

Recent Capacity Changes

In the Fall of 2003, Northwest completed two projects to reduce displacement. The Rockies Expansion Project included installation of approximately 91 miles of new pipeline loops and approximately 26,000 net horsepower of compression facilities at various locations in northwestern Wyoming and southeastern Idaho. This project increased Northwest's physical north flow capacity in the Kemmerer Corridor by approximately 175 MDth/day, to replace displacement capacity currently relied upon to serve existing north flow transportation service obligations in the Kemmerer, Wyoming, to Stanfield, Oregon, corridor. The Rockies Project was designed primarily to replace a contract-specific obligation that terminated October 31, 2003, to flow 144 MDth/day south to provide displacement in this corridor. The cost of this project was $140 million.

The Columbia Gorge Corridor facilities increased Northwest's physical north flow capacity in that corridor sufficient to replace approximately 54 MDth/day of displacement capacity currently relied upon to serve existing north flow transportation service obligations. The total estimated cost of this project is approximately $241 million, $198 million for the Sumas-Chehalis Corridor facilities and $43 million for the Columbia Gorge Corridor facilities. Northwest’s customers agreed to roll in the costs of both the Rockies and Columbia Gorge projects because they provide a general system benefit.

Northwest also completed an incremental project in October of 2003. The Evergreen Expansion Project included installation of approximately 28 miles of new pipeline loops and approximately 64,000 net horsepower of compression facilities in the Sumas-Chehalis Corridor in Washington State and installation of approximately 24,000 net horsepower of compression facilities in the Columbia Gorge Corridor in Washington. The Sumas-Chehalis Corridor facilities increases Northwest's physical south flow capacity in that corridor by approximately 2201 MDth/day to help provide 277 MDth/day of new long-term firm incremental transportation service for power generation loads.

Other Expansion Plans

Northwest has proposed to build the 9-mile, 16" MDth/day Everett-Delta Lateral to connect its system with that of Puget Sound Energy to serve business and population growth in Snohomish County. The lateral will have a capacity of 113 MDth/day and is expected to be in service on November 1, 2004. Williams is also a partner with BC Hydro on the GSX Project to serve power generation loads on Vancouver Island, B.C., as well as potential markets on the U.S. mainland.

National Energy & Gas Transmission Gas Transmission Northwest (GTN)

The majority of information contained in this section on the National Energy & Gas Transmission Gas Transmission Northwest (GTN) pipeline originated from the pipeline company itself via a survey conducted by the OTED Energy Policy Division and its contractors. The company was asked to provide information about the impact of new pipelines on their business, the ratio of gas from Canada versus the Rocky Mountains, major receipt points, largest shippers, capacity utilization, constraints, expansion plans, permitting process, storage and long-term plans.

System Overview

The GTN Pipeline interconnects with the TransCanada Pipeline at Kingsgate, B.C. Gas produced in Alberta is delivered to the Western United States via interconnections with the Northwest Pipeline at Spokane and Palouse, Washington, and Stanfield, Oregon; and Pacific Gas and Electric Company and Tuscarora Gas Transmission Company at Malin, Oregon. GTN also connects with Avista Utilities and Cascade Natural Gas.

GTN is a dual pipeline system consisting of approximately 612 miles of 36-inch diameter gas transmission line and approximately 612 miles of 42-inch-diameter pipe. The system also includes smaller diameter laterals to Coyote Springs and Medford. GTN can transport about 2.9 Bcf/day, or 2,900 MDth/day. More than 1,800 MDth/day can be delivered to California and Nevada and up to 1,000 MDth/day to the Pacific Northwest. In 2003, typical deliveries to the Pacific Northwest from the GTN system averaged 554 MDth/day in the winter and 385 MDth/day in the summer. In 2003, the peak day delivery to the Pacific Northwest from GTN was 954 MDth.

Pipeline Operation and Natural Gas Flows

Natural gas flow on the GTN system is essentially one-way from Canada to California. Gas can be delivered at various points along the system including three interconnection points with Northwest Pipeline and direct connects to local distribution companies such as Avista and Cascade Natural Gas. GTN also delivers to generators at Coyote Springs, Klamath Falls, Hermiston, Oregon; and Rathdrum, Idaho. Natural gas is received primarily from TransCanada Pipeline at Kingsgate, B.C., but GTN can receive a small amount of gas from the Northwest Pipeline at Stanfield. Even though there is not physical capacity to receive gas at other locations, it is possible to have nominations for receipt at other points by using displacement at other points on the system.

Canadian/domestic split gas supplies

GTN's system is a unidirectional pipeline that was built for and relies almost entirely upon Canadian gas. GTN's current contracts are 89 percent Canadian (receipts at Kingsgate) versus 11 percent domestic (receipts at Stanfield). For 2003, the ratio for the actual molecules delivered on GTN is approximately 8 percent domestic and 92 percent Canadian.

Contracted capacity

Table 7.5 below shows the major receipt points along GTN's system.

Table 7.5 Capacity at Major Receipt Points on GTN Pipeline

Location	Receipt Point Long-Term Firm Capacity (MDth/day)
Kingsgate	2,900
Stanfield	200
Total	*3,100*

Shippers, Contracts, and Delivery Points

Table 7.6 below shows the top shippers on GTN's system based on contracted demand.

Table 7.6 Top Ten Major Shippers, on GTN Pipeline, Contracted Delivery (Maximum Daily Quantity), and Primary Delivery Points

Company	Maximum Daily Quantity (MDth/d)	Primary Delivery Points
Pacific Gas and Electric Company	610	Malin
EnCana	166	Stanfield and Malin
Calpine	162	Malin and Hermiston
Avista	161	Various
Duke	136	Stanfield, Hermiston and Malin
Sierra Pacific Power	135	Stanfield and Malin
Pan-Alberta Gas	100	Stanfield
NW Natural	98	Spokane and Stanfield
Mirant	80	Stanfield and Malin
PPM Energy	66	Malin
Others	881	Various
Total Existing Long-Term Firm Contracts	*2,595*	

Subscribed capacity and actual capacity factor

Approximately 95.5 percent of GTN's system capacity is fully subscribed. GTN's actual capacity factor was approximately 69 percent in 2003.

Major physical constraint points

GTN has completed preliminary route feasibility studies for major pipeline laterals to serve growing market requirements, particularly for power generation, along the I-5 corridor in both Washington and Oregon. Either of the laterals could be in service within three years of establishing commitments from customers, or as early as mid 2007. While market growth will dictate the exact timeline, GTN expects to have them in service by the end of the decade. GTN has also completed study work on a potential future expansion of its mainline system. As with the lateral projects, market growth will dictate the exact timing of the expansion.

Expansion into new production areas

For the past two years GTN has been actively involved with a consortium of U.S. and Canadian pipeline companies in an effort to engage the Prudhoe Bay producers in a discussion around the commercial viability of a pipeline from the Alaska North Slope to Alberta, Canada. As a result of these discussions, GTN has developed plans to expand its mainline from the Canadian border near Kingsgate to the California border near Malin, Oregon. These expansion plans range in size from 100 MDth/d to 1,000 MDth/d of incremental capacity. These expansion plans will also accommodate new supplies from the MacKenzie River Delta.

GTN also recently concluded an open contract season for its North Baja Pipeline located in Southern California. The open season targeted liquified natural gas developers and resulted in seven requests totaling 5.5 Bcf/d to bring LNG onshore to Southwestern U.S. and Mexican markets by 2007.

Changes in storage capability

GTN has not changed its storage profile over the last three years.

Recent capacity changes

Approximately 211 MDth/d of annual service plus an additional 20,380 Dth/d of winter only service was added from Kingsgate, B.C., to Malin, Oregon, through GTN's 2002 Mainline Expansion. The expansion was placed in service on November 1, 2002. The cost of this project was approximately $129 million.

Upcoming changes

GTN may need an expansion in the next five years to provide mainline support for the two lateral projects previously described. GTN further expects to expand its mainline to provide DEGT access to the MacKenzie Delta region of Canada, Alaska or other Arctic gas supply within the decade.

Duke Energy Gas Transmission West (DEGT West)

The majority of information contained in this section on the DEGT West Pipeline[6] originated from the pipeline company itself via a survey conducted by the OTED Energy Policy Division and its contractors. The company was asked to provide information about the impact of new pipelines on its business, the ratio of gas from Canada versus the Rocky Mountains, major receipt points, largest shippers, capacity utilization, constraints, expansion plans, permitting process, storage and long-term plans.

System Overview

Duke Energy Gas Transmission West owns and operates a natural gas gathering, processing and transmission system in British Columbia, the Yukon and Northwest Territories. Through its subsidiary, Westcoast Gas Services Inc. (WGSI), DEGT West also manages and operates other gathering and processing assets in British Columbia. Through another subsidiary, Westcoast Transmission Company (Alberta) Ltd., DEGT West owns transmission facilities in Alberta that are connected to its federally regulated system.

The gathering, processing and transmission system is managed through three business units: the Field Services Division, which manages all National Energy Board of Canada (NEB) regulated gathering and processing facilities; the Pipeline Division, which manages all NEB and Alberta Energy and Utilities Board (AEUB) regulated transmission facilities; and WGSI, which manages the provincially regulated gathering and processing facilities in British Columbia.

The Field Services Division operates more than 2,800 kilometers of NEB regulated gathering lines and five processing plants that provide access to thousands of gas wells in the Western Canadian Sedimentary Basin -- an area that contains some of the most productive gas wells in North America.

DEGT West's plants have a gas processing capacity of approximately 1.8 Bcf/day and an approximate 67 percent market share of the British Columbia portion of the Western Canada Sedimentary Basin. Much of the gas found in Northern British Columbia contains high levels of sulphur, in the form of hydrogen sulphide. Processing this "sour" gas is a complex process that has resulted in the DEGT West system having fewer plants (of significantly larger size), which maximize economies of scale and minimize environmental impact. In contrast, the gas found in Alberta is largely "sweet" gas (low in sulphur), which lends itself to processing facilities that are less complex and generally of smaller capacity. As a result, Alberta gas processing is characterized by numerous smaller gas processing plants.

The Pipeline Division is the major transporter of natural gas in British Columbia. With 2,800 kilometers of transmission pipeline, the Pipeline Division facilities transport natural gas for suppliers to markets in western Canada and the U.S. Pacific Northwest. Approximately 53 percent of the annual throughput volumes for 2002 were exported

[6] Duke Energy Gas Transmission West (DEGT) was formerly called Westcoast Pipeline.

through Huntington for the U.S. Pacific Northwest markets. The remainder was delivered to markets in Canada and to a spur on the pipeline, which delivers gas to the Sumas Energy generating facility, petroleum refineries, and other industrial consumers just over the U.S. border.

The pipeline system is separated into three regions (North, Central, and South) for operating purposes. For tolling purposes the pipeline is divided into two segments -- transportation north and transportation south. In the Northern region, Alliance Pipeline takes delivery of gas from the DEGT West pipeline system at Gordondale, via the Westcoast (Alberta) system. The Southern transportation system travels through some of British Columbia’s most rugged terrain to bring gas from Station 2 to domestic and export markets in the U.S. Pacific Northwest.

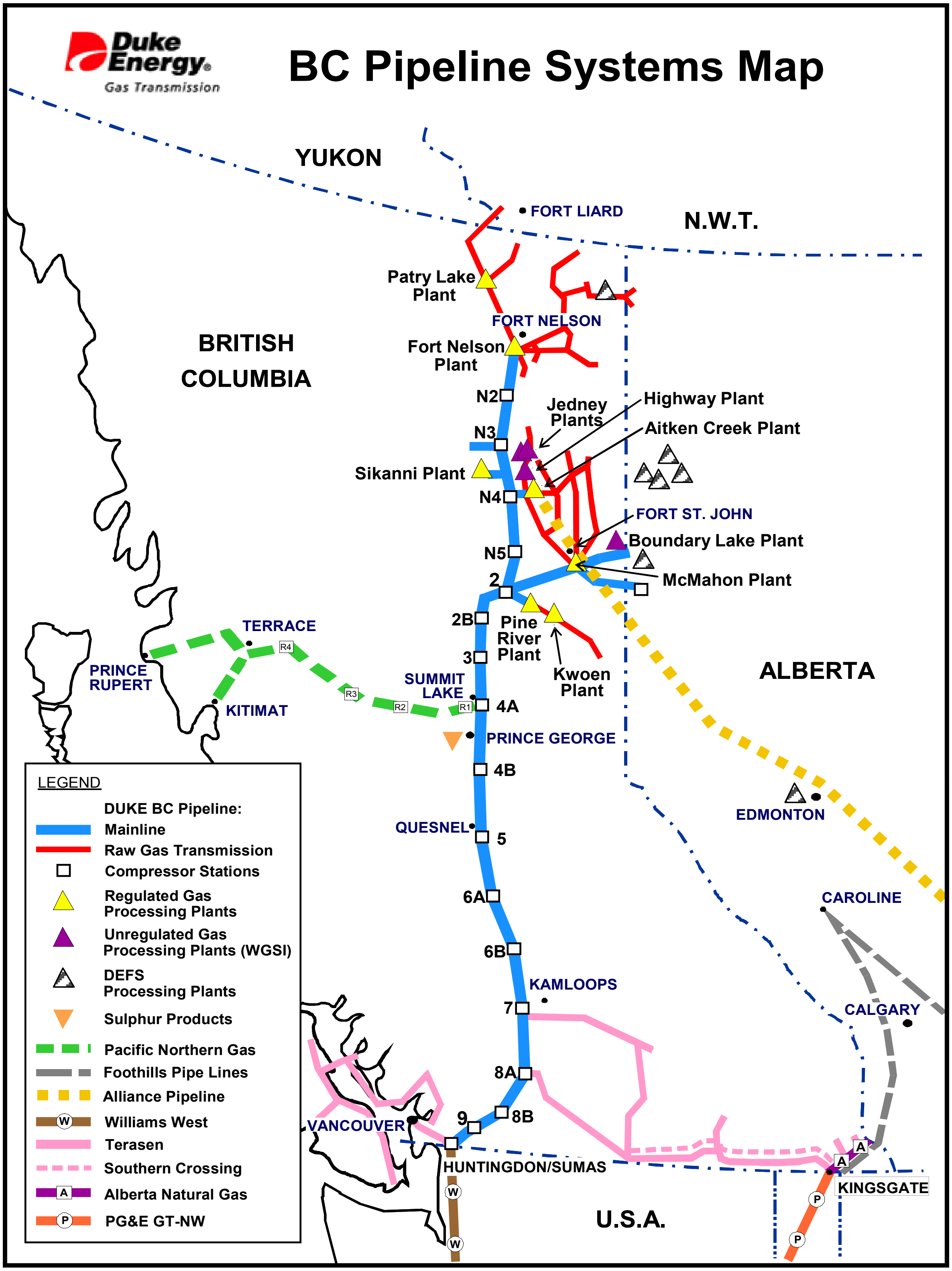

Figure 7.6: DEGT West System Map

Note: Since this map was created the name of PG&E Pipeline has changed to National Energy & Gas Transmission Gas Transmission Northwest (GTN) and Williams West Pipeline has changed its name to Northwest Pipeline.

Canadian/domestic split gas deliveries

The contract split between domestic (British Columbia) gas deliveries versus export deliveries (United States and Alberta) from the DEGT system is 37 percent to markets in British Columbia and 63 percent to export markets.

Contracted capacity at major receipt points

DEGT delivers gas to downstream pipelines, and therefore provides the contractual capacity at major delivery points along the system. The delivery capacity effective November 1, 2003, is provided in the following table.

Table 7.7 below shows the major receipt points along DEGT's system.

Table 7.7: Capacity at Major Receipt Points – DEGT Pipeline

	Total Capacity MMcf/d
Huntington/Sumas	1702
T-South -- Inland and Kingsvale	171
T-South -- Pacific Northern Gas	115
T-North -- Alliance/Gordondale	182
Total	2170

Shippers, Contracts, and Delivery Points

When contracting for transportation service on DEGT's system, shippers contract separately on the T-North system (north of compressor station #2) and the T-South system (south of station #2 to Huntington/Sumas). As illustrated below, the shipper groups on each pipeline segment differ.

On its T-North system, DEGT delivers gas to communities along its mainline, however, the majority of its deliveries are to Alliance Pipeline or to the NOVA system in Alberta via the ABC Gordondale Interconnect. It is important to note that the interconnection with NOVA at Gordondale is a bi-directional line. This feature allows gas to flow either eastbound into Alberta or westbound into British Columbia as the market conditions require. As illustrated in the table below, T-North shippers are composed primarily of natural gas producing companies. Additionally, there are less than 10 firm export shippers. Table 7.8 shows the top shippers on DEGT's T-North system based on contracted demand.

Table 7.8: Top Ten Major Shippers, Contracted Delivery (Maximum Daily Quantity), and Primary Delivery Points – DEGT T-North

Transportation North - Export Points		
Company	**Delivery Points**	**Max Daily Quantity (MMcf/day)**
Alliance Pipeline Ltd.	Alliance Boundary/Lake Interconnect	70
CanWest Gas Supply Inc.	ABC Gordondale Interconnect	27
Unocal Canada Limited	ABC Gordondale Interconnect	10
Dominion Exploration Canada	ABC Gordondale Interconnect	8
Anadarko Canada Corporation	ABC Gordondale Interconnect	7
ProGas Limited	ABC Gordondale Interconnect	5
Devon Canada Corporation	ABC Gordondale Interconnect	3
Canadian Natural Resources	ABC Gordondale Interconnect	1
Total		**130**

T-South shippers represent a combination of end use customers, producing companies and natural gas marketers. Table 7.9 shows the top shippers on DEGT's T-South system based on contracted demand. Delivery Points are T-South Inland (TSIND), T-South Lower Mainland (TSLM), T-South Export (TSEXP), and T-South Pacific Northern Gas (TSPNG).

Table 7.9: Top Ten Major Shippers, Contracted Delivery (Maximum Daily Quantity), and Primary Delivery Points – DEGT T-South

Transportation South		
Company	**Delivery Points**	**Maximum Daily Quantity (MMcf/day)**
Terasen Gas Inc.	TSIND, TSLM, TSEXP	535
Duke Energy Trading & Marketing	TSEXP	161
Canadian Natural Resources	TSEXP	75
Talisman Energy Canada	TSEXP	68
ExxonMobil Canada Energy	TSEXP	65
Anadarko Canada Corporation	TSEXP	62
CanWest Gas Supply Inc.	TSEXP	61
Methanex Corporation	TSPNG	58
Devon Canada Corporation	TSEXP	58
Northwest Natural Gas Company	TSEXP	56
All Other Shippers		765
Uncontracted Capacity		24
Total		**1988**

Subscribed capacity and actual capacity factor

As of November 1, 2003, approximately 96 percent of total capacity is subscribed. Because DEGT serves temperature sensitive markets in British Columbia and the Pacific Northwest, the load factor varies depending on the time of year. For example, for the year 2002, the annual load factor for the Southern mainline based on average daily flows was approximately 77 percent. For the 2002/2003 winter season, the load factor was approximately 87 percent. The maximum load factor achieved over the last year was on Dec. 18, 2002, when the Southern mainline operated at 96 percent of full capacity.

Major physical constraint points

DEGT is currently expanding its T-South pipeline system and this expansion will be placed in service November 1, 2003. The expansion, which originally contemplated the addition of 200 MMcf/d of incremental capacity, was reduced to 85 MMcf/d to reflect near-term changes in market conditions. While the project has been reduced, the National Energy Board has given approval for the full 200 MMcf/d expansion. Given this approval and should market conditions change such that additional incremental capacity is required, DEGT is well positioned to increase the capacity of T-South by an additional 115 MMcf/d. DEGT expects new capacity could be constructed in a timely manner since regulatory approvals are already in place. Therefore this increment of expansion can occur in a period of time that is much shorter than the original 30 months.

Other expansion plans

The DEGT system is not currently constrained. However, the company monitors the needs of markets and customers for incremental pipeline transport capacity. To the extent that market growth generates a requirement for additional capacity DEGT will conduct a contract open season to determine the interest of customers. This method aims to ensure that the system is not over built and transportation tolls are kept as low as possible.

Expansion into new production areas

DEGT plans to expand as producers capture new gas supplies from the Western Canadian Sedimentary Basin (WCSB) including Northeast British Columbia, the Southern Yukon and the Southern Northwest Territories. DEGT British Columbia will also expand its pipeline systems and processing facilities as supplies from interior basins and offshore British Columbia become available. These supplies are not expected to come on stream until after 2010. Duke Energy expects that both McKenzie Delta and Alaska gas will be required to meet future North American gas demands.

Changes in storage capability

DEGT currently does not own or operate storage facilities in British Columbia or the Pacific Northwest. DEGT is interested in developing future storage infrastructure in the Pacific Northwest but has no definitive plans at this point.

Recent capacity changes

Since January 2001, DEGT has had two major expansions of its pipeline system.

- <u>T-North Fort Nelson Expansion</u> – This expansion, totaling 43 MMcf/d of incremental capacity, was designed to connect growing supplies in the Fort Nelson, B.C. area to DEGT's mainline transmission system and to move this gas to Compressor Station

#2, the supply basin trading hub in British Columbia. The expansion went into service on November 1, 2002. The time period from the end of the open season to the in-service date was 15 months. The cost of this expansion was approximately $1.5 million Canadian.

- T-South Expansion – This expansion, which just came into service at the end of 2003, was in response to demands from the end use market. The expansion, which originally contemplated the addition of 200 MMcf/d of incremental capacity, was reduced to 85 MMcf/d to reflect near term changes in market conditions.

  The expansion consists of new compression at Station #8B and new compressor wheels at Station #9. The cost of this expansion is approximately $50 million Canadian.

Upcoming changes

DEGT anticipates that end use markets in British Columbia and the Pacific Northwest will grow on average by approximately 2.5 percent per year. The primary driver behind this growth is expected to arise from incremental gas-fired generation in the region.

As a common carrier, DEGT will respond to this growth with expansion of capacity and as the market requires. As previously noted, DEGT currently has NEB approval to add 200 MMcf/d of pipeline capacity to its southern mainline system (T-South). Given that it will only be adding 85 MMcf/d for November 1, 2003, the groundwork for constructing an incremental 115 MMcf/d has already been completed.

Natural Gas Storage

As Pipeline capacity demand in the Western United States continues to expand, the need for underground storage facilities to support this growth also is being addressed. In the Western region of the United States, more than 2,690 MMcf/d of proposed new pipeline capacity is related to development of storage infrastructure during 2003-2005.[7]

The Jackson Prairie Storage Facility located near Chehalis, Washington, is the third largest natural gas storage field in the world. It is located on the Northwest Pipeline system, and is co-owned in equal shares between the Northwest Pipeline Company, Puget Sound Energy and Avista Corporation. The Mist storage facility in Northwestern Oregon is owned by Northwest Natural.

These storage facilities are primarily used for seasonal storage to increase peak day deliverability. Gas is injected during off-peak periods and retrieved during the peak winter heating season. Refill begins in spring and continues through September, when 90-100 percent of capacity is usually achieved. As much as half of the gas used by consumers on a cold winter day comes from storage fields.

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[7] Source: EIA, Office of Oil and Gas, *Expansion and Change on the U.S. Natural Gas Pipeline Network*, 2002.

Jackson Prairie has a daily withdrawal capacity of 874 MDth. Working gas capacity is 18,300 MDth. Puget Sound Energy is the FERC-certified operator of Jackson Prairie. Northwest Pipeline is responsible for the scheduling, metering and accounting activities that are associated with the Jackson Prairie facilities. Puget and Avista use their portions of the stored gas to provide peak day deliverability for their core customers. Unneeded portions may be leased to third parties on an interim basis. Northwest Pipeline does not market natural gas -- its portion of the facility is either used to provide balancing gas or leased to shippers (Puget has arrangements for 15-20 percent of Northwest's share of Jackson Prairie).

The location of major storage facilities close to end-use customers allows storage to substitute for pipeline capacity in meeting peak demand days. Because gas can be shipped to storage facilities west of the Cascades during the summer when interstate pipelines operate at less than 100 percent capacity, these pipelines need not be sized to meet downstream peak demands. This means that the value of natural gas storage to the Northwest is not derived solely from winter/summer price differentials, but also from savings from avoided pipeline upgrades.

As the demand for natural gas for electricity generation increases, there may be less delivery capacity available during off-peak periods for injection into storage facilities, and the gas that is available may be more costly. If natural gas prices become more sensitive to the price of electricity, this may mean that natural gas will no longer be significantly cheaper during summer months. The risk management strategies historically used by local gas distribution utilities may need to be revised in order to minimize the cost of gas service to traditional core-market customers as gas-fired electric generation is added to regional natural gas demand.

Table 7.10 Natural Gas Storage Facilities Available to the Pacific Northwest

Name	Withdrawal Capacity (MMcf/day)	Pipeline	Location
Jackson Prairie	850	NWP	Centralia, WA
Clay Basin*	450	NWP	Northeast Utah
Plymouth LNG	300	NWP	Columbia Gorge area, WA
Mist	190	NWP	Northwest of Portland, OR
Gasco LNG	120	NWP	Near Portland, OR
Newport LNG	60	NWP	Newport, OR
Columbia Hills	(Proposed)	NWP and GTN	

* The Clay Basin storage facility is east of the Kemmerer Corridor, which is a potential constraint